EXHIBIT 1
DATE 4/1/2011
SB 415

SENATE BILL NO. 415

SPONSORED BY: Senator Bob Lake

House Federal Relations, Energy & Telecommunications
3:00 PM – Friday, April 1, 2011 – Room 172

"Generally Revising Oil & Gas Lease Laws"

By: Patrick M. Montalban, Lobbyist - NMOGA

NORTHERN MONTANA OIL & GAS ASSOCIATION
Prepared by: Patrick M. Montalban - Lobbyist

PLEASE VOTE FOR SENATE BILL 415

1. **Senate Bill No. 415 does not affect private landowners' rights to negotiate an oil and gas lease on their land with an oil company in the State of Montana.**

2. **Oil & Natural Gas Producing Companies pay all drilling, completion and production costs. This Bill is about transporting oil and gas to market and deducting post-production costs of gravity adjustment, BTU and compression**

3. **Correct for Oil Gravity: 40° Gravity:**
   In Northern Montana the average gravity is 30°

4. **Price Correction: $100.00/barrel to $84.00/barrel**

5. **Correct for BTU Adjustment:**
   1,000 BTU = 913 BTU Correction Northwestern – 9%

6. **Correction for Compressor Usage to Operate Gas Compressor: 17% Usage**

7. **Make the Dept of Revenue and Dept of Natural Resources and Conservation Consistent with what is allowed for post-production costs**

8. **Stop Audits and Lawsuits in our State---Not good for oil and gas business---does not create jobs**

PLEASE SUPPORT SENATE BILL 415

Respectfully Submitted,

Patrick M. Montalban
Lobbyist for the Northern Montana Oil & Gas Association

C H S INC

2000 S Main McPherson, KS 67460 620-241-9183

LEASE RUN STATEMENT

OPERATOR	MONTALBAN OIL & GAS OPERATIONS	59715
LEASE	KRUEGER 4,5,6,&	2000710
LOCATION	GLACIER, MT	

MONTALBAN OIL & GAS OPERATIONS
P O BOX 200
CUT BANK MT 59427

Mo/Day	Ticket #	Ent	Tank #	Gravity	Price	Net Barrels	Gross Value
02/12	21000701	1	2000689	27.0	76.8620	247.48	19,021.81

RECEI
MAR 11 20
MOGO,
3/11/2011

	Gross value	Total Taxes	Net Value		
February 2011	19,021.81	0.00	19,021.81	247.48	

ENTRY CODE
1 - REGULAR TICKET
2 - ESTIMATED TICKET

LAKE FRANCIS/WILLIAMS GAS FIELDS PRODUCTION
For the Month of January 2011

GAS FIELD	MCF		DAYS		PER DAY	
Lake Francis Production =	8,093,000		31		269,562	
Williams Gas Production	5,103,000		31		166,071	
TOTAL	13,196,000		31		435,633	
PLANT PRICE					$3.8087	
		Monthly Price/AECO	%loss		Per/ Mcf	
BTU Costs	1,092,000	$3.8087	9%	$4,159.10	$.32	
Compressor (Usage)Costs	2,162,910	$3.8087	17%	$8,235.14	$.63	
NW loss %			26%			
TOTAL LOSS COSTS						
TOTAL COSTS/mcf					$.95	
EXPENSES + COSTS/mcf					$2.8587	
NET EXPENSES/mcf						
Wellhead Price					$2.8587	
Total Field Production	13,196,000			Daily Usage		
Compressor Usage(W #1)	934,750			30,153		
Dehydrator Usage	194,000			6,258		
Comp. #2 usage (#2)	290,160			9,360		
Comp #3 Usage (#3)	744,000			24,000		
Farm Usage(2)	120,000			4,000	Monthly Usage	
	10,913,090			10,913,090		
Precision	10,843,000		NW	11,084,000		
	-70,090	= -.01%		+170,910	=+.02%	

GAS VOLUME STATEMENT

CLOSED DATA

Measured Conditions
In Service
2-0181-2 --- WILLIAMS FIELD REC PT CX RTU
January, 2011

Pressure Base: 14.900 psia **Temperature Base:** 60.00 °F **HV Cond:** Dry **Meter Type:** EFM **Contract Hr.:** 8 AM
Water Vapor Corr. Technique: **Water Vapor Corr. Method:**

CO2	N2	H2O	H2S	O2	He	C1	C2	C3	I-C4	N-C4	I-C5	N-C5	C6+
0.158	11.376		0.0000	0.000	0.000	87.907	0.445	0.073	0.017	0.015	0.000	0.000	0.010

Tube I.D.	Interval	Tap Location	Tap Type	Atmos. Pressure	Calc. Method	Fpv Method
4.020 in	1 Hour	Downstream	Flange	13.000 psi	AGA3-1992	AGA8-Detail

Day	Differential (In. H2O)	Pressure (PSIG)	Temperature (°F)	Hours Flow	Relative Density	Plate (inches)	Volume (Mcf)	Heating Value (BTU/scf)	Energy (MMBTU)
1	5.47	567.84	44.53	23.99	0.6068	1.000	367	913.20	335
2	5.51	569.53	47.59	23.98	0.6068	1.000	367	913.20	335
3	5.61	570.39	51.00	23.99	0.6068	1.000	369	913.20	337
4	5.50	570.44	50.05	23.97	0.6068	1.000	366	913.20	334
5	5.52	572.38	54.44	23.99	0.6068	1.000	365	913.20	334
6	5.92	574.03	58.69	23.99	0.6068	1.000	377	913.20	344
7	6.00	573.56	59.31	23.99	0.6068	1.000	379	913.20	346
8	5.79	566.31	46.35	23.99	0.6068	1.000	376	913.20	343
9	4.28	560.32	36.24	22.01	0.6068	1.000	250	913.20	228
10	4.86	562.01	36.65	23.97	0.6068	1.000	313	913.20	286
11	5.47	563.67	36.89	22.75	0.6068	1.000	348	913.20	317
12	5.33	566.09	42.23	23.99	0.6068	1.000	363	913.20	331
13	5.22	562.77	36.99	23.97	0.6068	1.000	355	913.20	324
14	4.12	560.75	33.73	20.13	0.6068	1.000	261	913.20	238
15	5.28	566.59	39.00	22.65	0.6068	1.000	337	913.20	308
16	5.11	571.05	46.17	23.96	0.6068	1.000	348	913.20	318
17	5.50	567.77	38.18	23.98	0.6068	1.000	371	913.20	339
18	5.50	569.20	45.91	23.97	0.6068	1.000	367	913.20	335
19	5.42	570.31	46.50	23.99	0.6068	1.000	365	913.20	333
20	5.36	571.06	47.76	23.99	0.6068	1.000	363	913.20	331
21	5.58	567.72	53.98	23.99	0.6068	1.000	366	913.20	334
22	5.63	566.65	53.52	23.99	0.6068	1.000	368	913.20	336
23	5.62	566.22	54.35	23.99	0.6068	1.000	367	913.20	335
24	5.69	568.25	58.87	23.99	0.6068	1.000	368	913.20	336
25	5.78	568.42	58.30	23.98	0.6068	1.000	371	913.20	338
26	5.84	567.85	58.15	24.00	0.6068	1.000	373	913.20	340
27	5.86	567.77	59.42	23.99	0.6068	1.000	373	913.20	340
28	5.86	567.31	59.54	23.99	0.6068	1.000	372	913.20	340
29	5.43	564.95	45.19	23.98	0.6068	1.000	364	913.20	332
30	5.20	559.48	33.17	23.98	0.6068	1.000	360	913.20	329
31	5.36	544.68	35.75	23.99	0.6068	1.000	359	913.20	328
TOTAL	5.47	566.81	47.78	735.11	0.6068		11,048 (19.)		10,084 / (89.) = .099

Volume at 14.730 = 11,176 Energy = 10,084

11,176,000 - 10,084,000 = 1,092,000 = .099

Moving the Molecules to Market:
An Introduction to Hydrocarbon Processing and Transportation

Monika Ehrman
Pioneer Natural Resources

Rocky Mountain Mineral Law Foundation
Oil & Gas Agreements: Midstream and Marketing
February 24, 2011

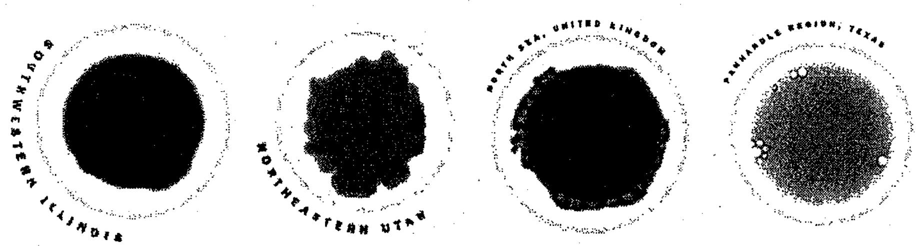
Overview

- Overview of hydrocarbon properties
- Hydrocarbon processing
  - Gathering
  - Separation
  - Water handling
  - Dehydration
  - Sweetening
  - Liquid extraction
  - Compression
  - Transportation
  - Metering
- Measurement standards

The views expressed in this paper are solely those of the author (or authors).
Please cite as: Ehrman, Monika, "Moving the Molecules to Market: An Introduction to Hydrocarbon Processing and Transportation," *Oil & Gas Agreements: Midstream and Marketing*, Paper No. 2, Page No. ___ (Rocky Mt. Min. L. Fdn. 2011).

Hydrocarbon Properties

- Oil and gas are the liquid and gaseous forms of petroleum
- Petroleum is any naturally-occurring hydrocarbon found beneath the earth



Source: Chevron

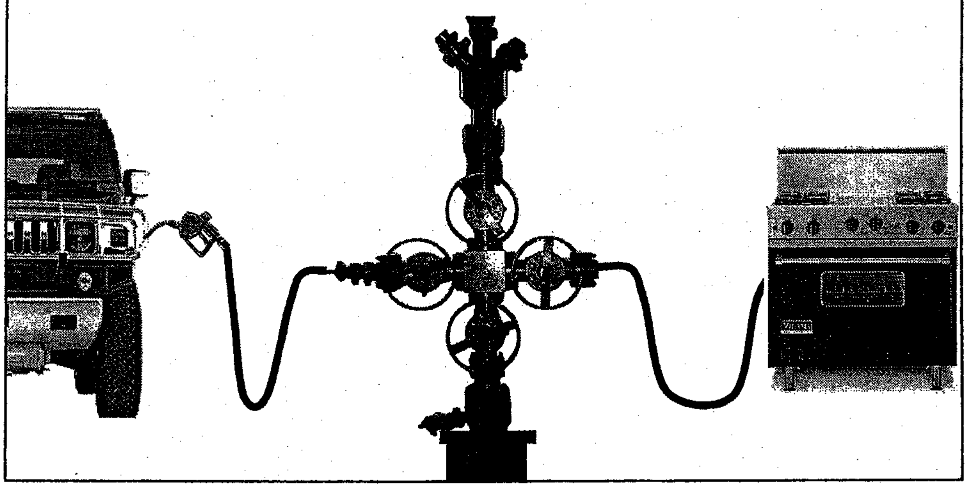
Hydrocarbon Properties

- Petroleum hydrocarbons are naturally-occurring organic compounds (carbon + hydrogen)
- Occur in a variety of states from solid to gaseous

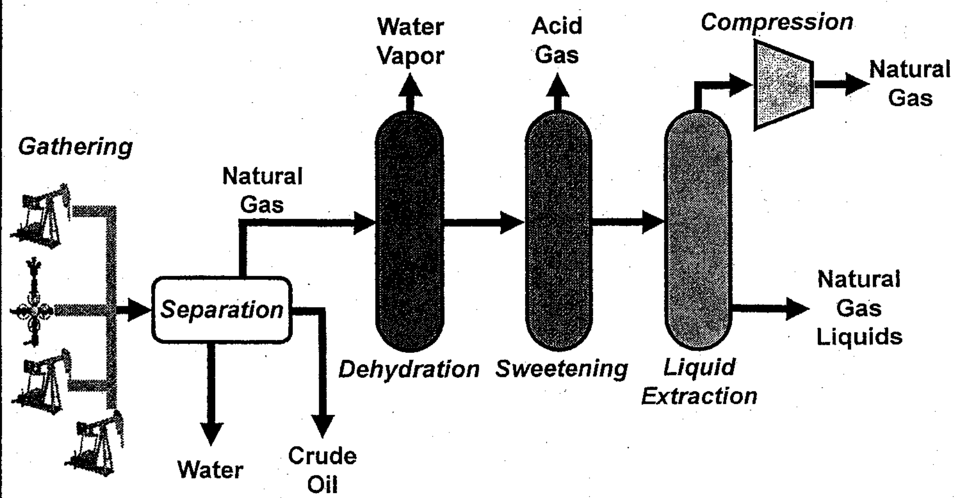
Increasing Hydrogen and Carbon Atoms

- Increase in Carbon and Hydrogen → Increase in chemical bonds → Increase in energy content

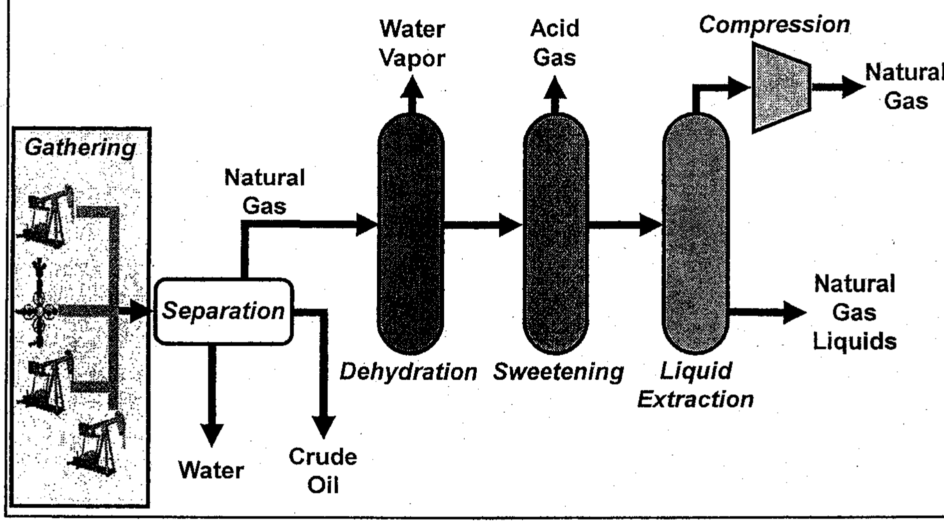
If only it were this simple.......



Hydrocarbon Processing



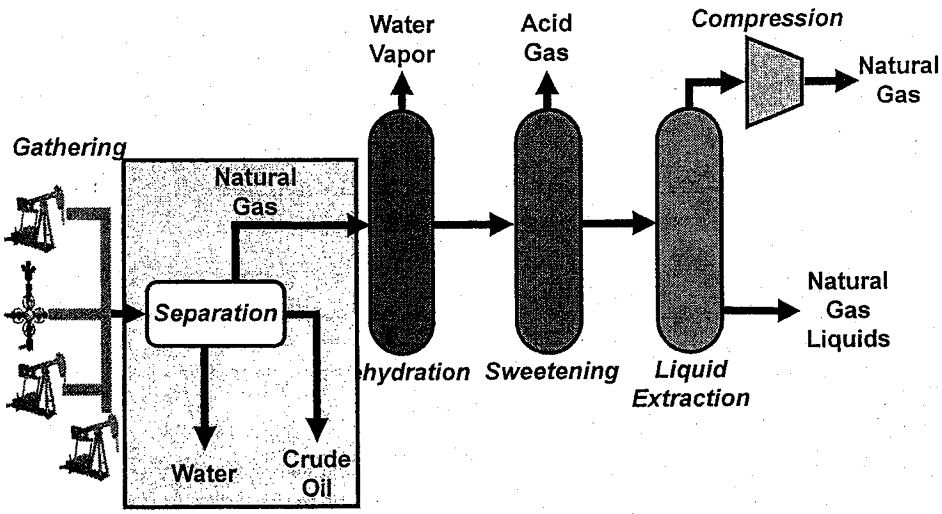
Hydrocarbon Processing



Gathering

- Too expensive for each wellhead to have own processing unit; system of flowlines connect wells to central processing facility (field processing area or processing plant)
  - Radial gathering system
  - Trunk line gathering system → Used in larger fields
- All produced fluids flow through gathering lines
- If no gathering system in place, fluids can be trucked → Not for gas wells

Hydrocarbon Processing



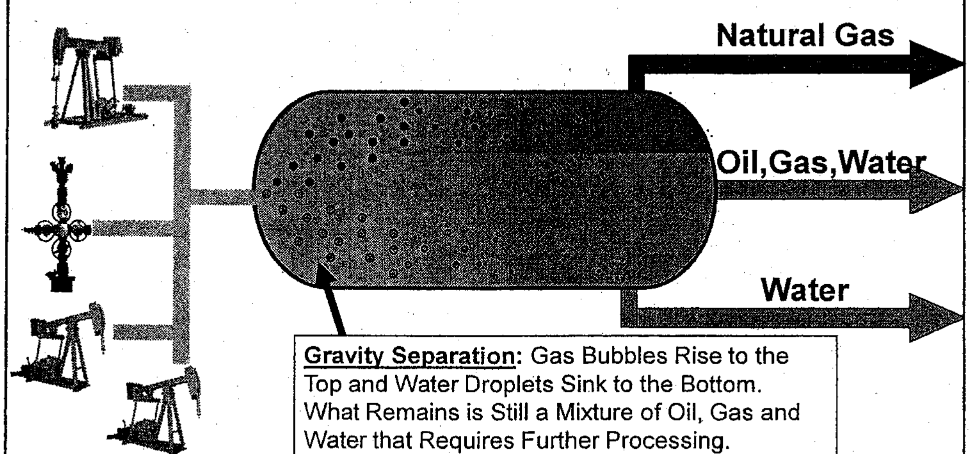
Separation

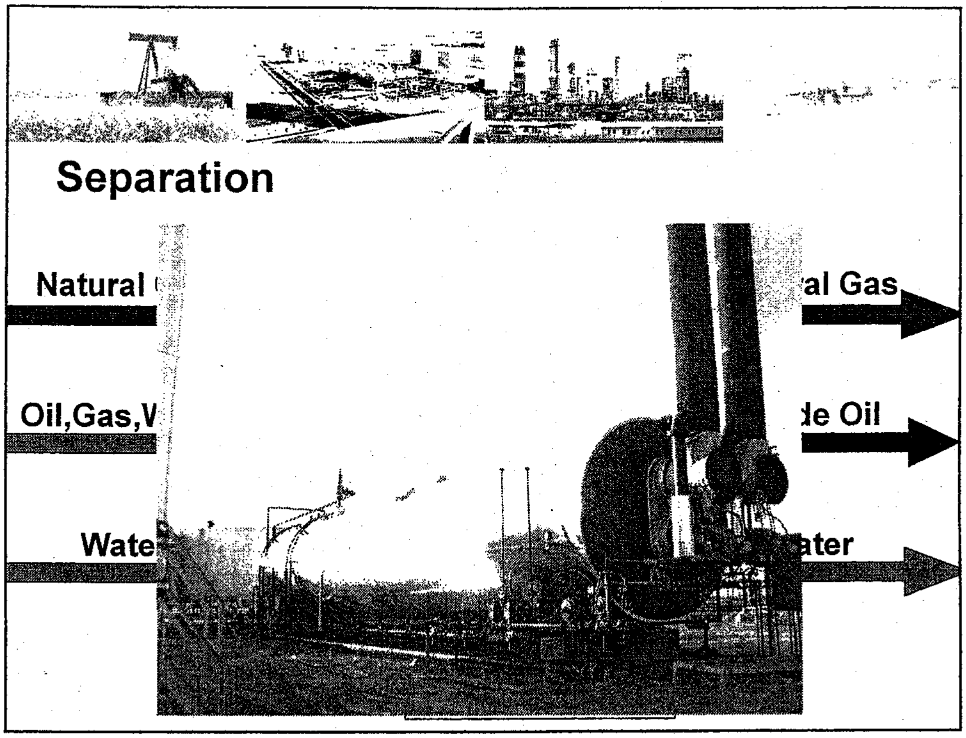
- Operation where well stream passed through 2+ separators arranged in series
  - First-stage separator, second-stage separator, etc.
- Purpose of multi-stage separation to maximize hydrocarbon liquid recovery and provide maximum stabilization to resultant phases leaving final separator
  - Well stream must be separated into three phases → Gas and liquids (oil and water)

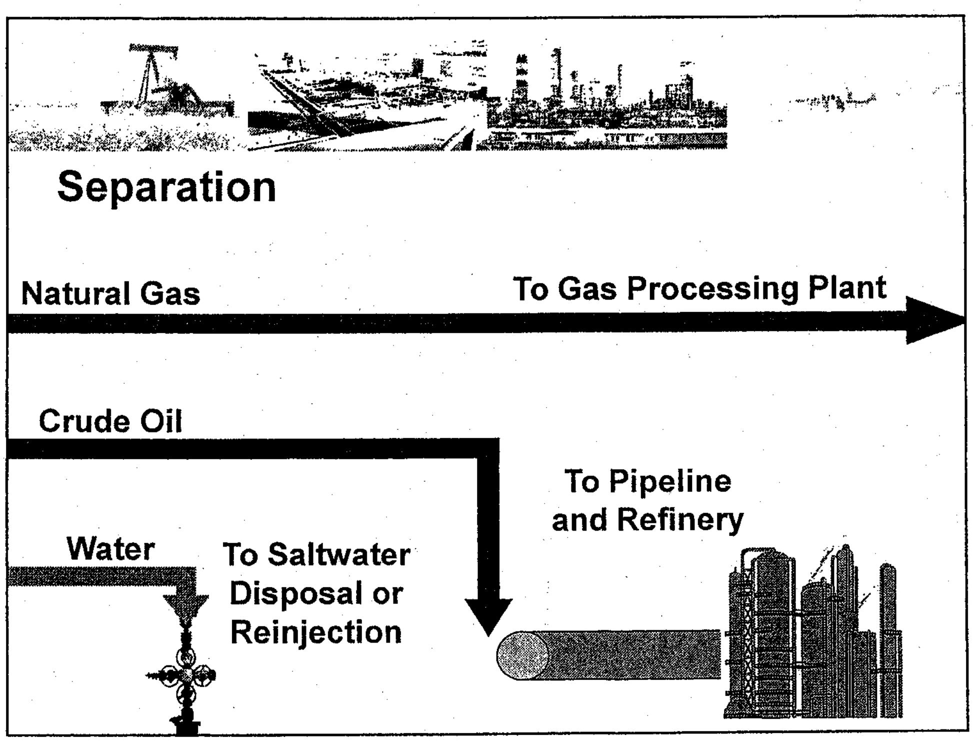
Separation

- Operation mainly uses gravity segregation
  - Inlet fluid flows against diverter plate that separates gas and liquid
  - Mist extractor collects liquid droplets from gas stream before it leaves separator
- Separators can be vertical, horizontal, or spherical depending on requirements
- If water cut is high, free water knock out vessel used for primary separation
- Heater/Treater used to treat oil-water emulsions

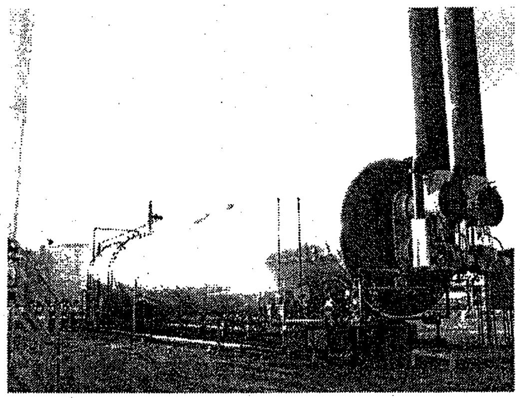
Separation




Separation
Natural
al Gas
Oil,Gas,V
le Oil
Wate
ater


Separation
Natural Gas
To Gas Processing Plant
Crude Oil
To Pipeline
and Refinery
Water
To Saltwater
Disposal or
Reinjection

Separation



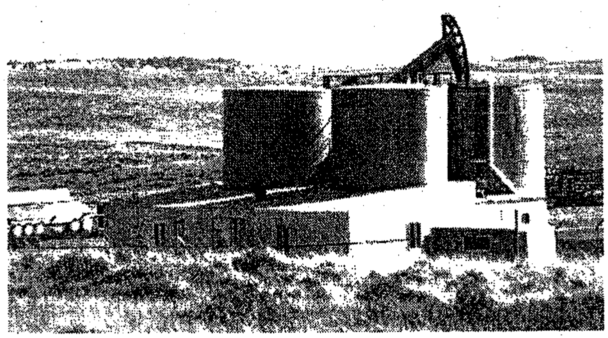
Separation – Crude Oil

- Oil flows into sales pipeline or tanks for storage
- If tanks are used, producers sell oil to third-party, who subcontracts with trucking company
- Important to negotiate risk of loss during transport
  - Indemnification language

Separation – Water Handling

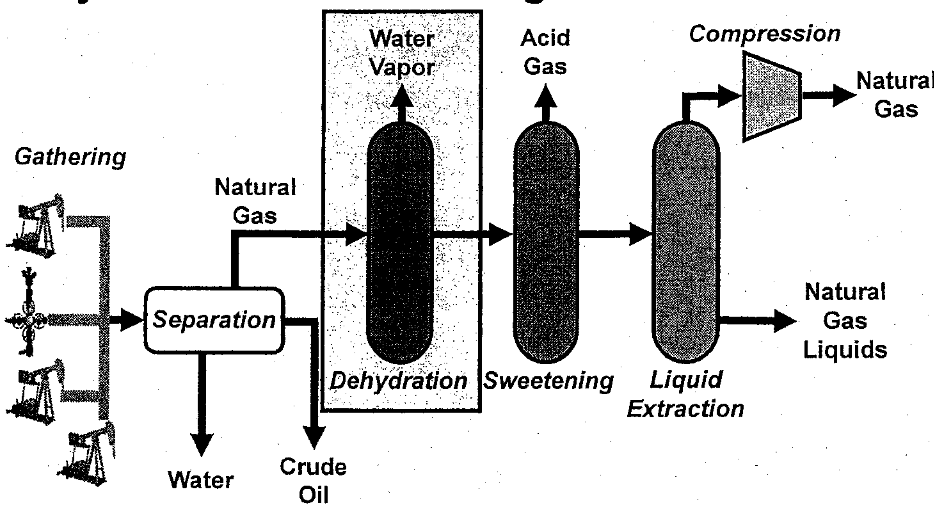
- If separation occurs at wellsite, water flows into tanks and is trucked to a processing facility
- Water tank has skimmer to remove any residual oil that floats to the top
- Water from separators used for reinjection (enhanced oil recovery) or sent to disposal well

Separation – Water Handling



Source: Wyoming Energy Resources Information Clearinghouse

Hydrocarbon Processing



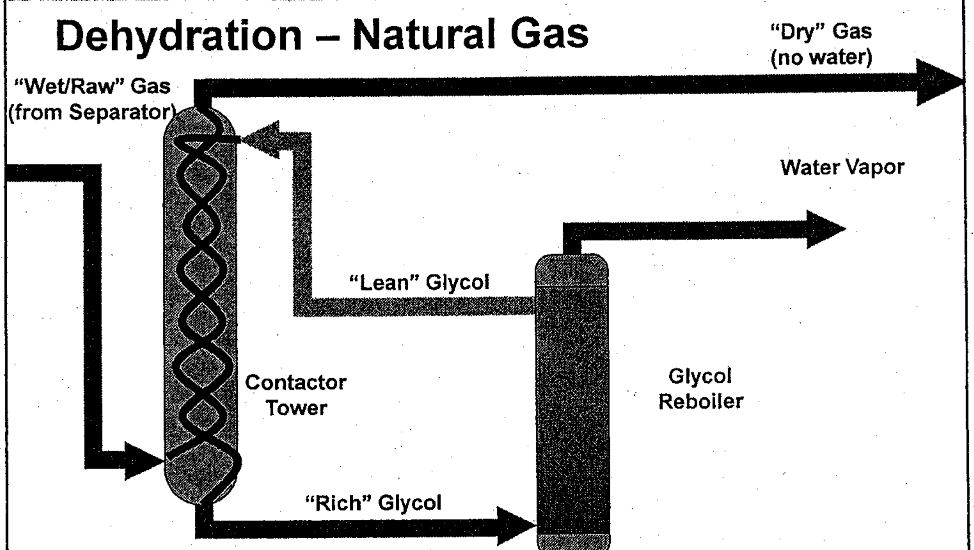
Dehydration – Natural Gas

- Even after separation, gas stream contains water vapor, which must be removed
  - Water reduces value of product
  - Corrosion problems
  - Hydrate formation
    - Formed by union of water with other substances
    - Can form in gas gathering facilities at reduced temperatures and high pressures
    - Can plug the pipelines and significantly affect production operations

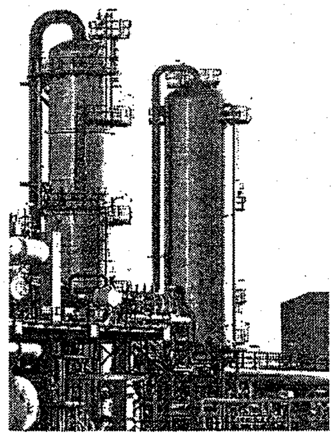
Dehydration – Natural Gas

- Operation used to remove water and water vapors from gas
  - Glycol dehydrator uses liquid desiccant
    - Glycols → Ethylene, diethylene, triethylene, etc.
  - Dry-bed dehydrator uses solid desiccant
    - Silica gel or calcium chloride ($CaCl_2$)
- Designed to handle only water and gas vapors

Dehydration – Natural Gas

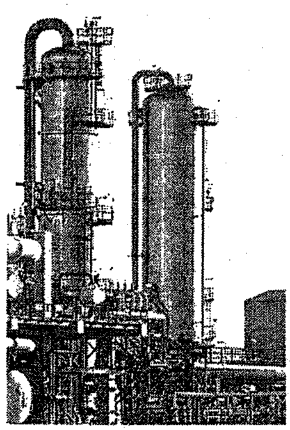


Dehydration – Natural Gas

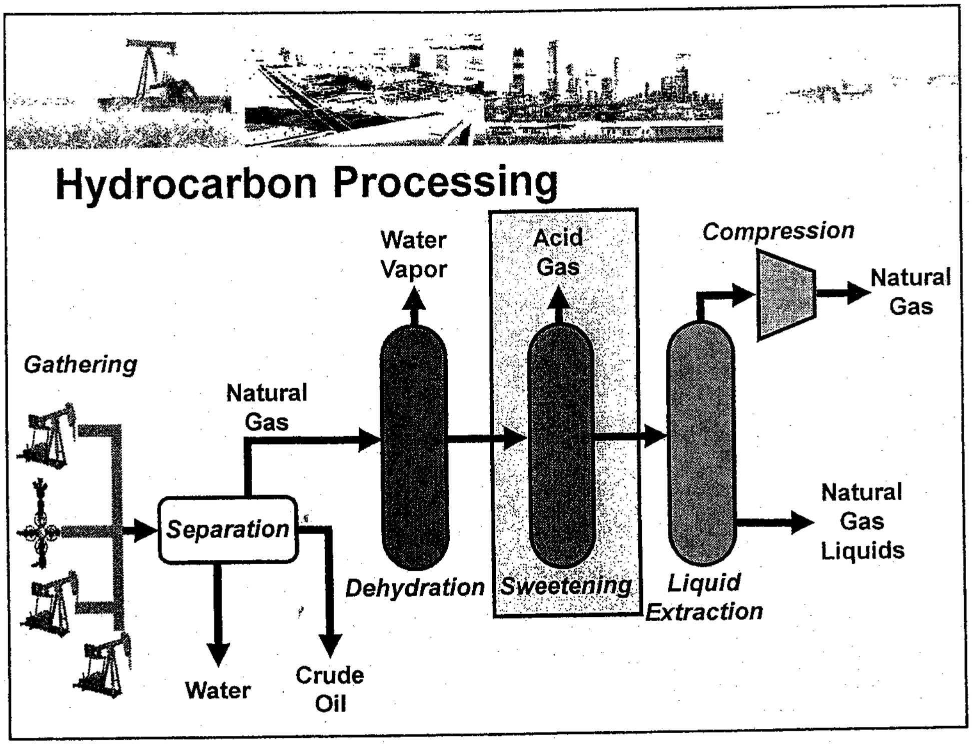


Source: Process-Facility.com

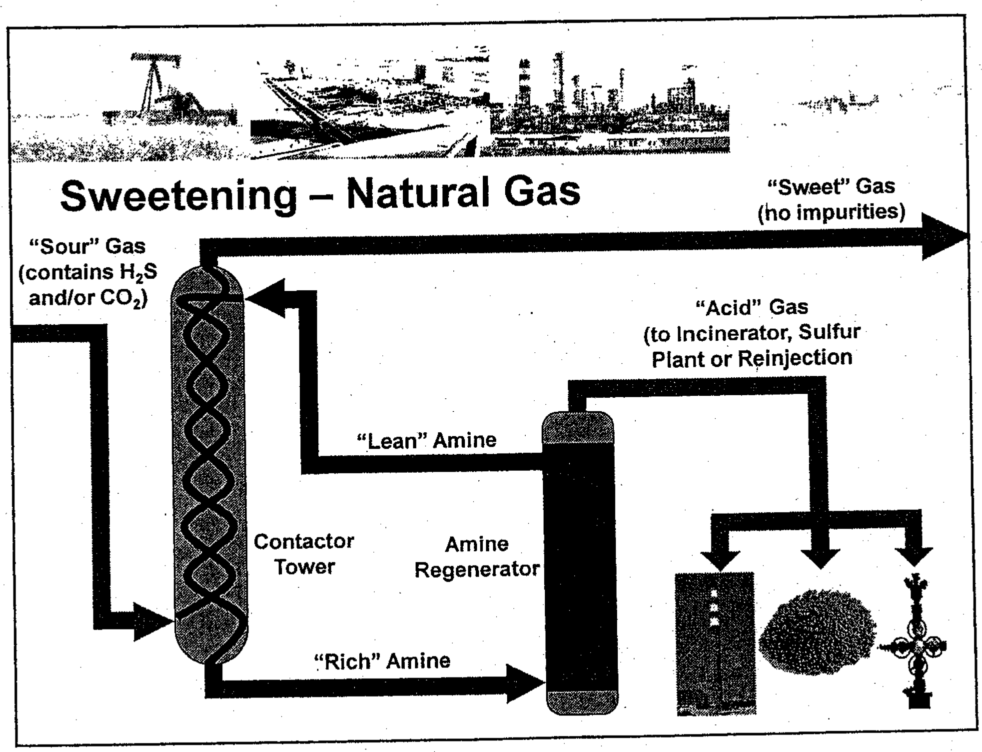
Dehydration – Natural Gas



Source: Source Petrochem Supply



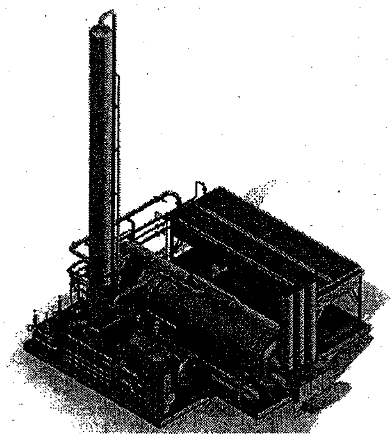
Hydrocarbon Processing
Water Vapor
Acid Gas
Compression
Natural Gas
Gathering
Natural Gas
Separation
Natural Gas Liquids
Dehydration
Sweetening
Liquid Extraction
Water
Crude Oil



Sweetening – Natural Gas
"Sweet" Gas (ho impurities)
"Sour" Gas (contains H_2S and/or CO_2)
"Acid" Gas (to Incinerator, Sulfur Plant or Reinjection
"Lean" Amine
Contactor Tower
Amine Regenerator
"Rich" Amine

Sweetening – Natural Gas

- Amine unit

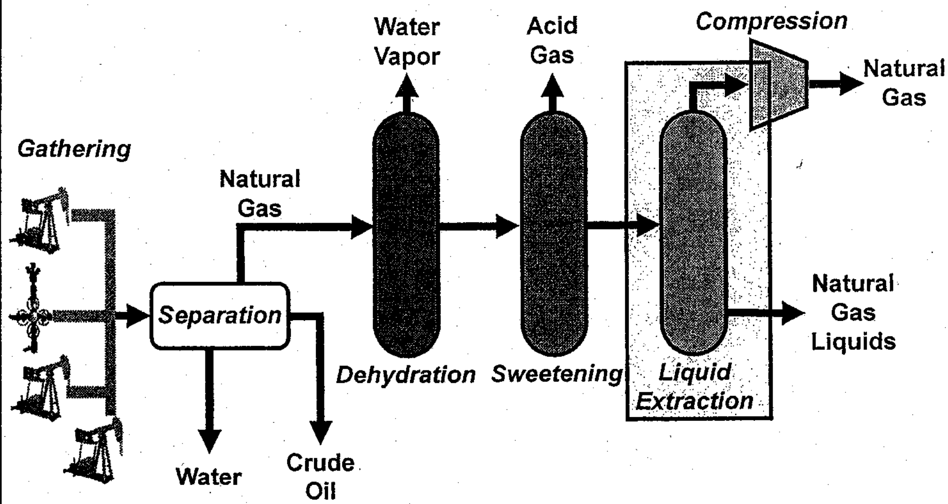

[illegible]

Sweetening – Natural Gas


- Sulphur block
- Difficult to dispose of or sell

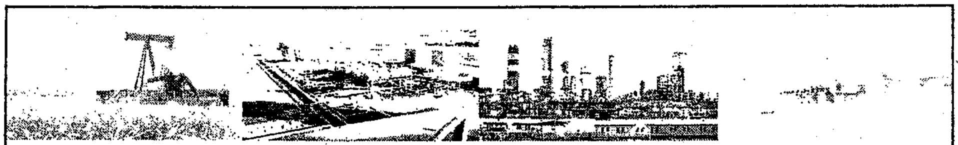
Source: www.folc.ca

Hydrocarbon Processing

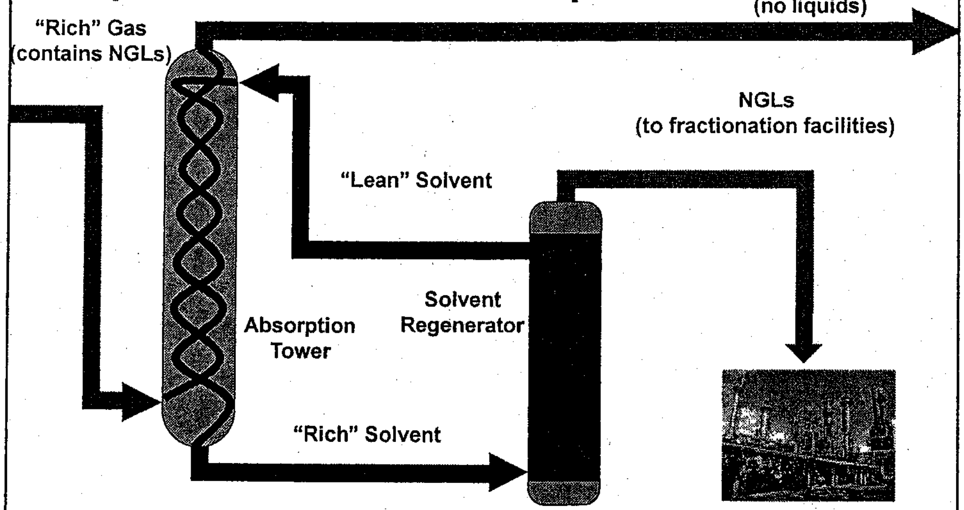


Liquid Extraction

- If natural gas liquids (NGLs) have higher value as separate products, liquids are removed from gas stream
- Removal process similar to dehydration process
  - Absorption method
    - Absorption method uses absorbing oil to attract NGLs
  - Cryogenic expansion method
    - Drop temperature to ~ -120F
    - Gas chilled using turbo expander process
      - Better at recovering lighter hydrocarbons (C_2+)



Liquid Extraction – Absorption



Liquid Extraction – Cryogenic

- Cryogenic method of extraction

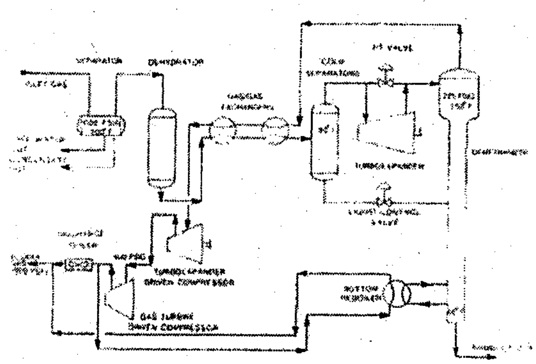
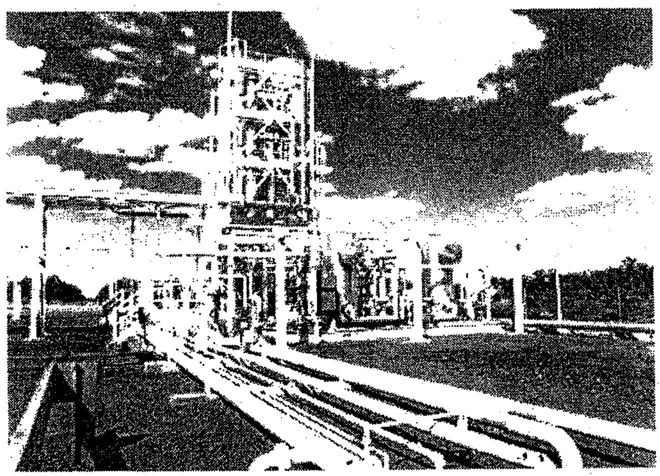


Figure 9-3. Simplified flow diagram of a cryogenic plant.

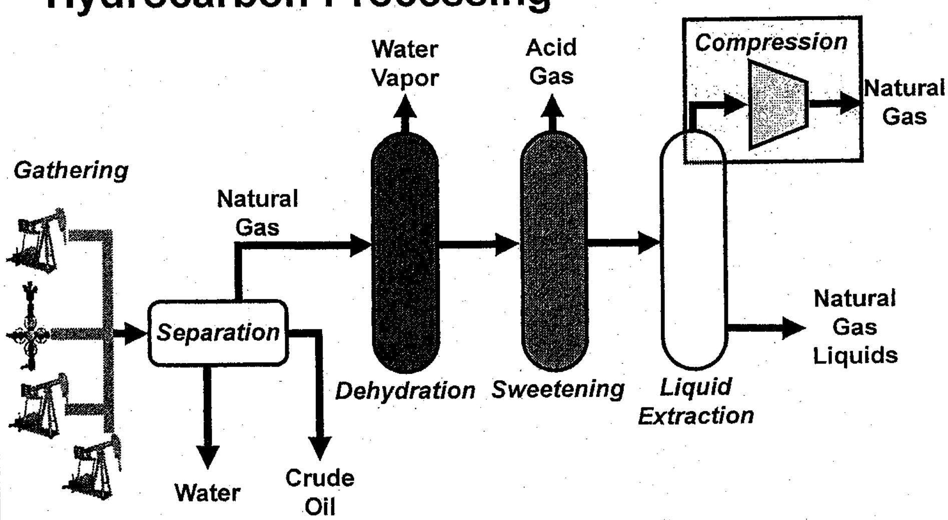
Source: www.process-facility.com

Liquid Extraction – Cryogenic



Source: www.natural-gas-liquids.com

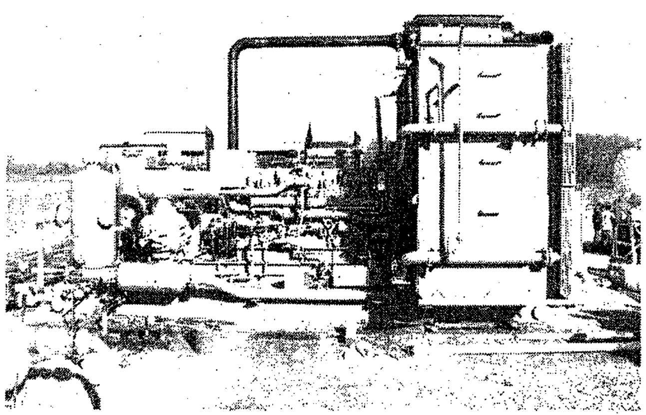
Hydrocarbon Processing



Compression

- Compression can be done at all stages of hydrocarbon processing → Interstage compression
  - Before processing, pressure may need to be increased (e.g., flow from low wellhead pressure to high separator pressures)
- Two main types of compressors used in gas industry
  - Reciprocating
  - Centrifugal
- Usually most expensive item in an upstream processing facility

Compression



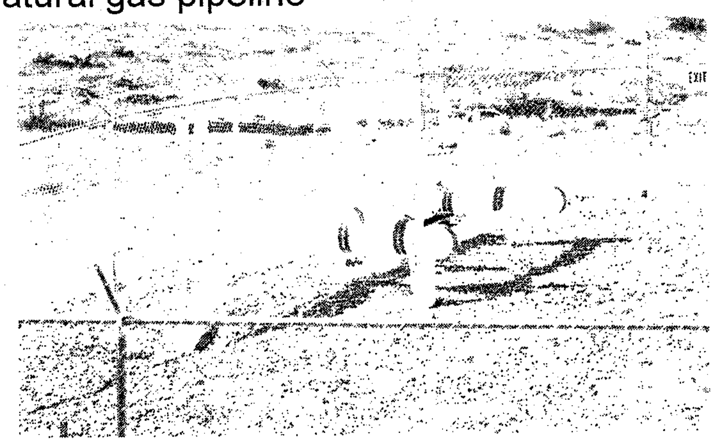
Source: Unger Technologies, Inc.

Transportation

- After processing, hydrocarbons taken to sales typically via large, interstate/intrastate transmission lines
- Point-of-transfer between producer/processor and third-party purchaser/pipeline is the sales meter at specified location
  - Transfer of title also determined in purchase and sale agreement

Transportation

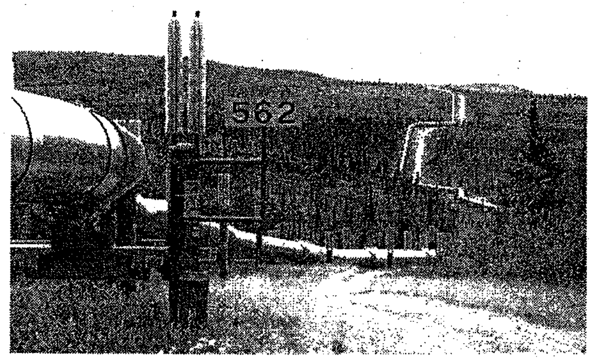
- Natural gas pipeline



Source: Pegasus News

Transportation

- Crude oil pipeline



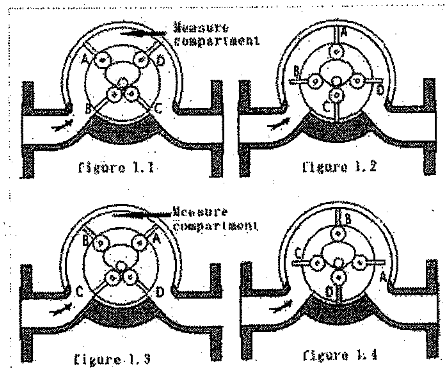
Source: American Society of Civil Engineers

Metering

- Common types of meters:
  - Direct / Positive displacement
    - Used for liquids
    - Mechanically isolate and pass known volume of liquid with every revolution
  - Inferential / Differential Pressure
    - Used for gas
    - Velocity (gas flow rate) inferred from pressure differential caused by flowing gas through a restriction in the line (orifice plate)

Metering

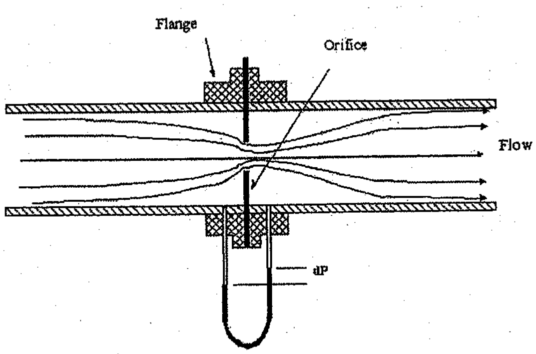
- Positive displacement meter



Source: DDTOP Manufacture & Trade Technology

Metering

- Orifice meter



Source: Penn State

Measurement Standards – Natural Gas

- Terms set forth in gas purchase and sale contract
- Found within contract or as exhibit to contract (e.g., Standard/General Terms & Conditions)
- Terms usually address:
  - Receipt and delivery pressure
  - Gas quality
    - Grains of sulphur and hydrogen sulphide
    - Volume of oxygen and carbon dioxide
    - Temperature
    - Water vapor content
    - Bacteria-free

Measurement Standards – Crude Oil

- Terms set forth in purchase confirmation:
  - Specific Gravity
    - Scale developed by API for measuring relative density of petroleum liquids (degrees)
  - Reid Vapor Pressure
    - Common measure of and generic term for gasoline volatility
- Conoco Terms and Conditions (1993) usually attached to or referenced in crude oil contract

Reference Material

- American Petroleum Institute (API) Standards
- GPSA Engineering Data Books
- Appendices
  - Appendix A: EIA Natural Gas Processing Overview
  - Appendix B: Example of General Terms & Conditions
  - Appendix C: Conoco General Provisions

Contact Information

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(972) 444-9001

www.pxd.com

Appendix A

Natural Gas Processing: The Crucial Link Between Natural Gas Production and Its Transportation to Market

This special report examines the processing plant segment of the natural gas industry, providing a discussion and an analysis of how the gas processing segment has changed following the restructuring of the natural gas industry in the 1990s and the trends that have developed during that time. It focuses upon the natural gas industry and its capability to take wellhead quality production, separate it into its constituent parts, and deliver pipeline-quality natural gas (methane) into the nation's natural gas transportation network. Questions or comments on the contents of this article may be directed to James Tobin at James.Tobin@eia.doe.gov or (202) 586-4835, Phil Shambaugh at Phil.Shambaugh@eia.doe.gov or 202-586-4833, or Erin Mastrangelo at Erin.Mastrangelo@eia.doe.gov or (202)-586-6201.

The natural gas product fed into the mainline gas transportation system in the United States must meet specific quality measures in order for the pipeline grid to operate properly. Consequently, natural gas produced at the wellhead, which in most cases contains contaminants[1] and natural gas liquids,[2] must be processed, i.e., cleaned, before it can be safely delivered to the high-pressure, long-distance pipelines that transport the product to the consuming public. Natural gas that is not within certain specific gravities, pressures, Btu content range, or water content levels will cause operational problems, pipeline deterioration, or can even cause pipeline rupture (see Box, "Pipeline-Quality Natural Gas").[3]

Although the processing/treatment segment of the natural gas industry rarely receives much public attention, its overall importance to the natural gas industry became readily apparent in the aftermath of Hurricanes Katrina and Rita in September 2005. Heavy damage to a number of natural gas processing plants along the U.S. Gulf Coast, as well as to offshore production platforms and gathering lines, caused pipelines that feed into these facilities to suspend natural gas flows while the plants attempted to recover.[4] While several processing plants in southern Mississippi and Alabama were out of commission for only a brief period following Katrina, 16 processing plants in Louisiana and Texas with a total capacity of 9.71 billion cubic feet per day (Bcf/d) and a pre-hurricane flow volume of 5.45 Bcf/d were still offline 1 month following the two storms.[5] Consequently, a significant portion of the usual daily output that flowed into the interstate pipeline network from the tailgates of these plants was disrupted, in some cases indefinitely.

Pipeline-Quality Natural Gas

The natural gas received and transported by the major intrastate and interstate mainline transmission systems must meet the quality standards specified by pipeline companies in the "General Terms and Conditions (GTC)" section of their tariffs. These quality standards vary from pipeline to pipeline and are usually a function of a pipeline system's design, its downstream interconnecting pipelines, and its customer base. In general, these standards specify that the natural gas:

- Be within a specific Btu content range (1,035 Btu per cubic feet, +/- 50 Btu)
- Be delivered at a specified hydrocarbon dew point temperature level (below which any vaporized gas liquid in the mix will tend to condense at pipeline pressure)
- Contain no more than trace amounts of elements such as hydrogen sulfide, carbon dioxide, nitrogen, water vapor, and oxygen
- Be free of particulate solids and liquid water that could be detrimental to the pipeline or its ancillary operating equipment.

Gas processing equipment, whether in the field or at processing/treatment plants, assures that these tariff requirements can be met. While in most cases processing facilities extract contaminants and heavy hydrocarbons from the gas stream, in some cases they instead blend some heavy hydrocarbons into the gas stream in order to bring it within acceptable Btu levels. For instance, in some areas coalbed methane production falls below the pipeline's Btu standard, in which case a blend of higher btu-content natural gas or a propane-air mixture is injected to enrich its heat content (Btu) prior for delivery to the pipeline. In other instances, such as at LNG import facilities where the heat content of the regasified gas may be too high for pipeline receipt, vaporized nitrogen may be injected into the natural gas stream to lower its Btu content.

In recent years, as natural gas pricing has transitioned from a volume basis (per thousand cubic feet) to a heat-content basis (per million Btu), producers have tended, for economic reasons, to increase the Btu content of the gas delivered into the pipeline grid while decreasing the amount of natural gas liquids extracted from the natural gas stream. Consequently, interstate pipeline companies have had to monitor and enforce their hydrocarbon dew point temperature level restrictions more frequently to avoid any potential liquid formation within the pipes that may occur as a result of producers maximizing Btu content.

[1]Includes non-hydocarbon gases such as water vapor, carbon dioxide, hydrogen sulfide, nitrogen, oxygen, and helium.

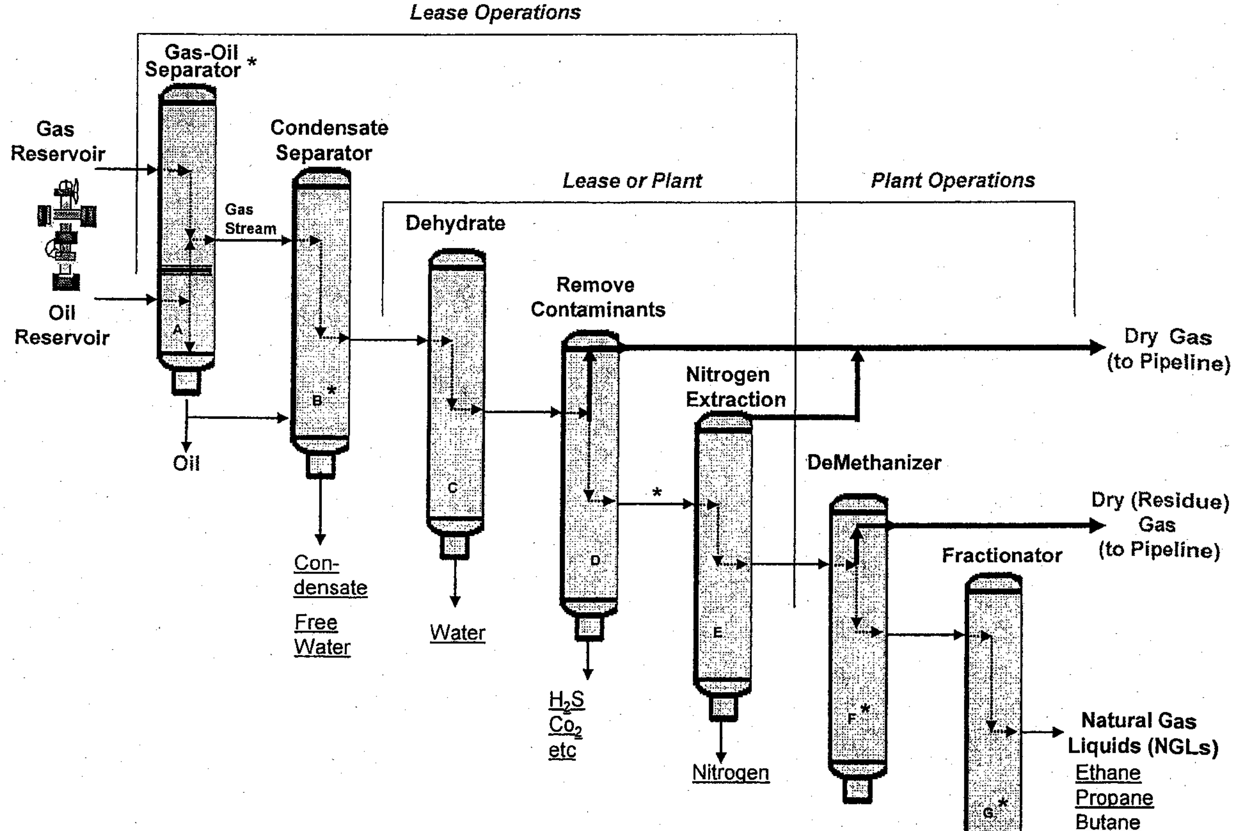
[2]Ethane, propane, and butane are the primary heavy hydrocarbons (liquids) extracted at a natural gas processing plant, but other petroleum gases, such as isobutane, pentanes, and normal gasoline, also may be processed.

[3]For a detailed examination of the subject see Joseph Wardzinski, et al., "Interstate Natural Gas – Quality Specifications & Interchangeability," Center for Energy Economics, Bureau of Economic Geology, The University of Texas at Austin (Houston, Texas, December 2004). http://www.beg.utexas.edu/energyecon/lng/

[4]Some of these feeder pipelines also had to suspend operations because they themselves suffered damage, the production platforms that they serviced were damaged, or the connecting pipelines were damaged.

[5]Department of Energy, "DOE's Hurricane Response Chronology" provided by Secretary Samuel Bodman at Senate Energy and Natural Resources Committee Hearing, October 27, 2005.

Figure 1. Generalized Natural Gas Processing Schematic



* Optional Step, depending upon the source and type of gas stream.
•Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Division.

In 2004, approximately 24.2 trillion cubic feet (Tcf) of raw natural gas was produced at the wellhead.[6] A small portion of that, 0.1 Tcf, was vented or flared, while a larger portion, 3.7 Tcf, was re-injected into reservoirs (mostly in Alaska) to maintain pressure. The remaining 20.4 Tcf of "wet"[7] natural gas was converted into the 18.9 Tcf of dry natural gas that was put into the pipeline system. This conversion of wet natural gas into dry pipeline-quality natural gas, and the portion of the natural gas industry that performs that conversion, is the subject of this report.

Background

Natural gas processing begins at the wellhead (Figure 1). The composition of the raw natural gas extracted from producing wells depends on the type, depth, and location of the underground deposit and the geology of the area. Oil and natural gas are often found together in the same reservoir. The natural gas produced from oil wells is generally classified as "associated-dissolved," meaning that the natural gas is associated with or dissolved in crude oil. Natural gas production absent any association with crude oil is classified as "non-associated." In 2004, 75 percent of U.S. wellhead production of natural gas was non-associated.

Most natural gas production contains, to varying degrees, small (two to eight carbons) hydrocarbon molecules in addition to methane. Although they exist in a gaseous state at underground pressures, these molecules will become liquid (condense) at normal atmospheric pressure. Collectively, they are called condensates or natural gas liquids (NGLs). The natural gas extracted from coal reservoirs and mines (coalbed methane) is the primary exception, being essentially a mix of mostly methane and carbon dioxide (about 10 percent).[8]

[6]Energy Information Administration, *Natural Gas Annual 2004* (December 2005), Table 1. http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/natural_gas_annual/nga.html.

[7]Wet gas is defined as the volume of natural gas remaining after removal of condensate and uneconomic nonhydrocarbon gases at lease/field separation facilities and less any gas used for repressurization.

[8]The Energy Information Administration estimates that about 9 percent of 2004 U.S. dry natural gas production, or about 1.7 Tcf, came from coalbed methane sources, which do not contain any natural gas liquids. *U.S. Crude Oil and Natural Gas, and Natural Gas Liquids Reserves: 2004 Annual Report*. http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/

Natural gas production from the deepwater Gulf of Mexico and conventional natural gas sources of the Rocky Mountain area is generally rich in NGLs and typically must be processed to meet pipeline-quality specifications. Deepwater natural gas production can contain in excess of 4 gallons of NGLs per thousand cubic feet (Mcf) of natural gas compared with 1 to 1.5 gallons of NGLs per Mcf of natural gas produced from the continental shelf areas of the Gulf of Mexico. Natural gas produced along the Texas Gulf Coast typically contains 2 to 3 gallons of NGLs per Mcf.[9]

The processing of wellhead natural gas into pipeline-quality dry natural gas can be quite complex and usually involves several processes to remove: (1) oil; (2) water; (3) elements such as sulfur, helium, and carbon dioxide; and (4) natural gas liquids (see Box, "Stages in the Production of Pipeline-Quality Natural Gas and NGLs"). In addition to those four processes, it is often necessary to install scrubbers and heaters at or near the wellhead. The scrubbers serve primarily to remove sand and other large-particle impurities. The heaters ensure that the temperature of the natural gas does not drop too low and form a hydrate with the water vapor content of the gas stream. These natural gas hydrates are crystalline ice-like solids or semi-solids that can impede the passage of natural gas through valves and pipes.

The wells on a lease or in a field are connected to downstream facilities via a process called gathering, wherein small-diameter pipes connect the wells to initial processing/treating facilities. Beyond the fact that a producing area can occupy many square miles and involve a hundred or more wells, each with its own production characteristics, there may be a need for intermediate compression, heating, and scrubbing facilities, as well as treatment plants to remove carbon dioxide and sulfur compounds, prior to the processing plant (see Box "Other Key Byproducts of Natural Gas Processing"). All of these factors make gathering system design a complex engineering problem.

In those few cases where pipeline-quality natural gas is actually produced at the wellhead or field facility, the natural gas is moved directly to receipt points on the pipeline grid. In other instances, especially in the production of non-associated natural gas, field or lease facilities referred to as "skid-mount plants" are installed nearby to dehydrate and decontaminate raw natural gas into acceptable pipeline-quality gas for direct delivery to the pipeline grid. These compact "skids" are often specifically customized to process the type of natural gas produced in the area and are a relatively inexpensive alternative to transporting the natural gas to distant large-scale plants for processing.

[9] Enterprise Products Partners LP, Annual SEC 10K filing, 2004, p. 18.

Natural gas pipeline compressor stations,[10] especially those located in production areas, may also serve as field level processing facilities. They often include additional facilities for dewatering natural gas and for removal of many hydrocarbon liquids. Some pipeline compressor stations located along the coast of the Gulf of Mexico, for instance, are set up to process offshore production to a degree permitting delivery of a portion of its natural gas throughput directly into the pipeline grid. The remaining portion is forwarded to a natural gas processing plant for further processing and extraction of heavy liquids.

Non-pipeline-quality production is piped to natural gas processing plants for liquids extraction and eventual delivery of pipeline-quality natural gas at the plant tailgate. A natural gas processing plant typically receives gas from a gathering system and sends out processed gas via an output (tailgate) lateral that is interconnected to one or more major intra- and inter-state pipeline networks. Liquids removed at the processing plant usually will be taken away by pipeline to petrochemical plants, refineries, and other gas liquids customers. Some of the heavier liquids are often temporarily stored in tanks on site and then trucked to customers.

Various types of processing plants have been utilized since the mid-1850s to extract liquids, such as natural gasoline, from produced crude oil. However, for many years, natural gas was not a sought after fuel. Prior to the early 20th century, most of it was flared or simply vented into the atmosphere, primarily because the available pipeline technology permitted only very short-distance transmission.[11]

It was not until the early 1920s, when reliable pipe welding techniques were developed, that a need for natural gas processing arose. Yet, while a rudimentary network of relatively long-distance natural gas pipelines was in place by 1932, and some natural gas processing plants were installed upstream in major production areas,[12] the depression of the 1930s and the duration of World War II slowed the growth of natural gas demand and the need for more processing plants.[13]

After World War II, particularly during the 1950s, the development of plastics and other new products that required natural gas and petroleum as a production component

[10] All compressor stations contain some type of separation facilities which are designed to filter out, before compression, any water and/or hydrocarbons that may form in the gas stream during transport.

[11] William L. Leffler, "The Technology and Economic Behavior of the U.S. Propane Industry" (Tulsa , Oklahoma, 1973, The Petroleum Publishing Company), Chapter 1.

[12] Most of these pipelines extended from the Texas Panhandle and Louisiana to the Midwestern United States. Gas processing plants for these systems were located primarily in the Houghton Basin of northern Texas/Oklahoma/Kansas and the Katy area of eastern Texas.

[13] Arlon R. Tusing & Bob Tippee, "The Natural Gas Industry: Evolution, Structure, and Economics" (Tulsa, Oklahoma, 1995, Pennwell Publishing Company).

Stages in the Production of Pipeline-Quality Natural Gas and NGLs

The number of steps and the type of techniques used in the process of creating pipeline-quality natural gas most often depends upon the source and makeup of the wellhead production stream. In some cases, several of the steps shown in Figure 1 may be integrated into one unit or operation, performed in a different order or at alternative locations (lease/plant), or not required at all. Among the several stages (as lettered in Figure 1) of gas processing/treatment are:

A) **Gas-Oil Separators**: In many instances pressure relief at the wellhead will cause a natural separation of gas from oil (using a conventional closed tank, where gravity separates the gas hydrocarbons from the heavier oil). In some cases, however, a multi-stage gas-oil separation process is needed to separate the gas stream from the crude oil. These gas-oil separators are commonly closed cylindrical shells, horizontally mounted with inlets at one end, an outlet at the top for removal of gas, and an outlet at the bottom for removal of oil. Separation is accomplished by alternately heating and cooling (by compression) the flow stream through multiple steps. Some water and condensate, if present, will also be extracted as the process proceeds.

B) **Condensate Separator**: Condensates are most often removed from the gas stream at the wellhead through the use of mechanical separators. In most instances, the gas flow into the separator comes directly from the wellhead, since the gas-oil separation process is not needed. The gas stream enters the processing plant at high pressure (600 pounds per square inch gauge (psig) or greater) through an inlet slug catcher where free water is removed from the gas, after which it is directed to a condensate separator. Extracted condensate is routed to on-site storage tanks.

C) **Dehydration**: A dehydration process is needed to eliminate water which may cause the formation of hydrates. Hydrates form when a gas or liquid containing free water experiences specific temperature/pressure conditions. Dehydration is the removal of this water from the produced natural gas and is accomplished by several methods. Among these is the use of ethylene glycol (glycol injection) systems as an absorption* mechanism to remove water and other solids from the gas stream. Alternatively, adsorption* dehydration may be used, utilizing dry-bed dehydrators towers, which contain desiccants such as silica gel and activated alumina, to perform the extraction.

D) **Contaminant Removal**: Removal of contaminates includes the elimination of hydrogen sulfide, carbon dioxide, water vapor, helium, and oxygen. The most commonly used technique is to first direct the flow though a tower containing an amine solution. Amines absorb sulfur compounds from natural gas and can be reused repeatedly. After desulphurization, the gas flow is directed to the next section, which contains a series of filter tubes. As the velocity of the stream reduces in the unit, primary separation of remaining contaminants occurs due to gravity. Separation of smaller particles occurs as gas flows through the tubes, where they combine into larger particles which flow to the lower section of the unit. Further, as the gas stream continues through the series of tubes, a centrifugal force is generated which further removes any remaining water and small solid particulate matter.

E) **Nitrogen Extraction**: Once the hydrogen sulfide and carbon dioxide are processed to acceptable levels, the stream is routed to a Nitrogen Rejection Unit (NRU), where it is further dehydrated using molecular sieve beds. In the NRU, the gas stream is routed through a series of passes through a column and a brazed aluminum plate fin heat exchanger. Using thermodynamics, the nitrogen is cryogenically separated and vented. Another type of NRU unit separates methane and heavier hydrocarbons from nitrogen using an absorbent* solvent. The absorbed methane and heavier hydrocarbons are flashed off from the solvent by reducing the pressure on the processing stream in multiple gas decompression steps. The liquid from the flash regeneration step is returned to the top of the methane absorber as lean solvent. Helium, if any, can be extracted from the gas stream in a Pressure Swing Adsorption (PSA) unit.

F) **Methane Separation**: The process of demethanizing the gas stream can occur as a separate operation in the gas plant or as part of the NRU operation. Cryogenic processing and absorption methods are some of the ways to separate methane from NGLs. The cryogenic method is better at extraction of the lighter liquids, such as ethane, than is the alternative absorption method. Essentially, cryogenic processing consists of lowering the temperature of the gas stream to around -120 degrees Fahrenheit. While there are several ways to perform this function the turbo expander process is most effective, using external refrigerants to chill the gas stream. The quick drop in temperature that the expander is capable of producing condenses the hydrocarbons in the gas stream, but maintains methane in its gaseous form.The absorption* method, on the other hand, uses a "lean" absorbing oil to separate the methane from the NGLs. While the gas stream is passed through an absorption tower, the absorption oil soaks up a large amount of the NGLs. The "enriched" absorption oil, now containing NGLs, exits the tower at the bottom. The enriched oil is fed into distillers where the blend is heated to above the boiling point of the NGLs, while the oil remains fluid. The oil is recycled while the NGLs are cooled and directed to a fractionator tower. Another absorption method that is often used is the refrigerated oil absorption method where the lean oil is chilled rather than heated, a feature that enhances recovery rates somewhat.

G) **Fractionation**: Fractionation, the process of separating the various NGLs present in the remaining gas stream, uses the varying boiling points of the individual hydrocarbons in the stream, by now virtually all NGLs, to achieve the task. The process occurs in stages as the gas stream rises through several towers where heating units raise the temperature of the stream, causing the various liquids to separate and exit into specific holding tanks.

* Adsorption is the binding of molecules or particles to the surface of a material, while absorption is the filling of the pores in a solid. The binding to the surface is usually weak with adsorption, and therefore, usually easily reversible.

Sources: Compiled from information available at the following Internet web sites: American Gas Association (http://www.naturalgas.org/naturalgas/naturalgas.asp), Environmental Protection Agency (http://www.epa.gov/ttn/chief/ap42/ch05/final/c05s03.pdf), Cooper Cameron Inc. (http://www.coopercameron.com/cgi-bin/petreco/products/products.cfm?pageid=gastreatment), AdvancedExtractionTechnologies, Inc. (http://www.aet.com/gtip1.htm#refriglean), SPM-3000 Gas Oil Separation Processing (GOSP) (http://www.simtronics.com/ catalog/spm/spm3000.htm), and Membrane Technology and Research, Inc. (http://www.mtrinc.com/Pages/NaturalGas/ng.html#).

Other Key Byproducts of Natural Gas Processing

While natural gas liquids, such as propane and butane, are the byproducts most often related to the natural gas recovery process, several other products are also extracted from natural gas at field or gas treatment facilities.

Helium (He)

The world's supply of helium comes exclusively from natural gas production. The single largest source of helium is the United States, which produces about 80 percent of the annual world production of 3.0 billion cubic feet (Bcf). In 2003, U.S. production of helium was 2.4 Bcf, about two-thirds of which came from the Hugoton Basin in north Texas, Oklahoma, and Kansas (Figure 2). The rest mostly comes from the LaBarge field located in the Green River Basin in western Wyoming, with small amounts also produced in Utah and Colorado. According to the National Research Council, the consumption of helium in the United States doubled between 1985 and 1996, although its use has leveled off in recent years. It is used in such applications as magnetic resonance imaging, semiconductor processing, and in the pressurizing and purging of rocket engines by the National Aeronautics and Space Administration.

Twenty-two natural gas treatment plants in the United States currently produce helium as a major byproduct of natural gas processing. Twenty of these plants, located in the Hugoton-Panhandle Basin, produce marketable helium which is sold in the open market when profitable, while transporting the remaining unrefined helium to the Federal Helium Reserve (FHR). The FHR was created in the 1950s in the Bush salt dome, underlying the Cliffside field, located near Amarillo, Texas. Sales of unrefined helium in the United States for the most part, come from the FHR.

Carbon Dioxide (CO_2)

While most carbon dioxide is produced as a byproduct of processes other than natural gas treatment, a significant amount is also produced during natural gas processing in the Permian Basin of western Texas and eastern New Mexico. A limited amount is also produced in western Wyoming. In 2004 about 6.2 Bcf of carbon dioxide was produced in seven plants in the United States.

The carbon dioxide produced at these natural gas treatment plants is used primarily for re-injection in support of tertiary enhanced oil recovery efforts in the local production area. The smaller, uneconomic, amounts of carbon dioxide that are normally removed during the natural gas processing and treatment in the United States are vented to the atmosphere.

Hydrogen Sulfide (H_2S)

Almost all the elemental sulfur today is sulfur recovered from the desulfurization of oil products and natural gas. Hydrogen sulfide is extracted from a natural gas stream, or condensate, that is referred to as "sour." It is passed through a chemical solution that removes hydrogen sulfide and carbon dioxide, which are then fed to plants where the hydrogen sulfide is converted to elemental sulfur. The small quantities of non-sulfur components are incinerated and vented into the atmosphere. "Sour" condensate from plant inlet separators is fed to a condensate stabilizer where hydrogen sulfide and lighter hydrocarbons are removed, compressed, and then cycled to sulfur plants.

coincided with improvements in pipeline welding and pipeline manufacturing techniques. The increased demand for natural gas as an industrial feedstock and industrial fuel supported the growth of major natural gas transportation systems, which in turn improved the marketability and availability of natural gas for residential and commercial use.

Consequently, as the natural gas pipeline network itself became more efficient and regulated, the need for more and better natural gas processing increased both the number and operational efficiencies of natural gas processing plants.

National Overview

More than 500 natural gas processing plants currently operate in the United States (Table 1). Most are located in proximity to the major gas/oil producing areas of the Southwest and the Rocky Mountain States (Figure 2).[14] Not surprisingly, more than half of the current natural gas processing plant capacity in the United States is located convenient to the Federal offshore, Texas, and Louisiana. Four of the largest capacity natural gas processing/treatment plants are found in Louisiana while the greatest number of individual natural gas plants is located in Texas.

Although Texas and Louisiana still account for the larger portion of U.S. natural gas plant processing capability, other States have moved up in the rankings somewhat during the past 10 years as new trends in natural gas production and processing have come into play. For instance:

[14]The largest gas producing areas and States in 2004 were Texas onshore, the Federal offshore (waters off Texas, Louisiana, Alabama, and Mississippi), Oklahoma, New Mexico, Wyoming, Louisiana onshore, Colorado, and Kansas.

Table 1. Natural Gas Processing Plant Capacity in the Lower 48 States, 1995 and 2004

State	Natural Gas Processing Capacity (Million cubic feet per day)				Number of Natural Gas Processing/Treatment Plants				Percentage Change 1995 to 2004	
	In 2004	Percent of Total U.S.	In 1995	Percent of Total U.S.	In 2004	Percent of Total U.S.	In 1995	Percent of Total U.S.	In Capacity	In Number
Louisiana	16,512	27.3	15,569	28.0	61	11.5	87	12.0	6.1	-29.9
Texas	15,825	26.1	18,259	32.9	166	31.3	278	38.2	-13.3	-40.3
Wyoming	6,920	11.4	4,730	8.5	45	8.5	53	7.3	46.3	-15.1
Kansas	3,533	5.8	3,424	6.2	10	1.9	11	1.5	3.2	-9.1
New Mexico	3,427	5.7	3,697	6.7	25	4.7	34	4.7	-7.3	-26.5
Oklahoma	3,438	5.7	4,220	7.6	59	11.1	100	13.8	-18.5	-41.0
Illinois	2,202	3.6	2	--	2	0.4	1	0.1	--	100.0
Colorado	2,093	3.5	1,490	2.7	43	8.1	40	5.5	40.5	7.5
Mississippi	1,572	2.6	40	0.1	6	1.1	5	0.7	--	20.0
Alabama	1,310	2.2	468	0.8	15	2.8	12	1.7	179.9	25.0
California	1,037	1.7	925	1.7	24	4.5	31	4.3	12.1	-22.6
Utah	970	1.6	779	1.4	16	3.0	13	1.8	24.5	23.1
Michigan	483	0.8	524	0.9	16	3.0	19	2.6	-7.8	-15.8
West Virginia	460	0.8	421	0.8	8	1.5	7	1.0	9.3	14.3
North Dakota	222	0.4	241	0.4	8	1.5	9	1.2	-7.9	-11.1
Kentucky	154	0.3	178	0.3	3	0.6	5	0.7	-13.5	-40.0
Montana	133	0.2	115	0.2	3	0.6	8	1.1	15.7	-62.5
Florida	90	0.1	361	0.6	1	0.2	2	0.3	-75.1	-50.0
Arkansas	67	--	70	0.1	7	1.3	6	0.8	-4.3	16.7
Pennsylvania	62	0.1	20	--	9	1.7	2	0.3	210.0	350.0
Ohio	23	--	23	--	3	0.6	3	0.4	--	0.0
Nebraska	0	--	10	--	0	0.0	1	0.1	NA	NA
Total Lower 48 States	**60,533**	**100.0**	**55,566**	**100.0**	**530**	**100.0**	**727**	**100.0**	**8.9**	**-27.1**

Note: -- = less than .05 or greater than 999.99 percent. Although more than 8 billion cubic feet per day of gas processing capacity exists in the State of Alaska, almost all of the natural gas that is extracted does not enter any transmission system. Rather, it is re-injected into reservoirs.

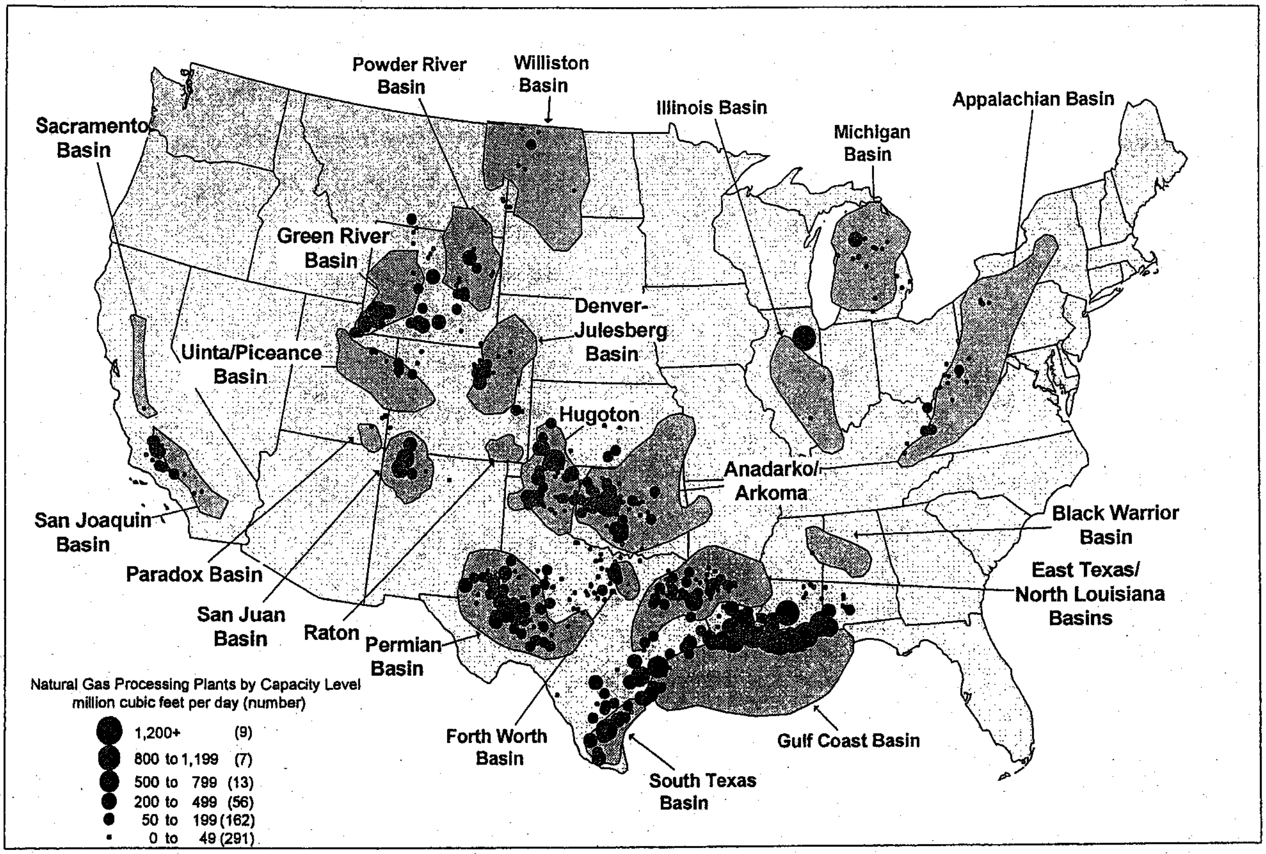
Source: Energy Information Administration, Gas Transportation Information System, Natural Gas Processing Plant Database (Compiled from data available from the Form EIA-64A, Form EIA-816, PentaSul Inc's *LPG Almanac*, and Internet sources.)

- **The Aux Sable natural gas plant, one of the largest natural gas processing plants in the Lower 48 States with an initial design capacity of 2.2 Bcf/d, was built in 2000 in Illinois, a State that has little or no natural gas production of its own.** Located at the receiving end of the Alliance Pipeline, which was built specifically to transport "wet" natural gas from British Columbia and Alberta, Canada, to Aux Sable, the plant currently processes about 1.5 Bcf daily, separating methane from natural gas liquids. The plant's northern Illinois location was selected to take economic advantage of extracting natural gas liquids in the Chicago (hub) area with its easy access to several hydrocarbon products pipelines, while delivering "dry" natural gas to the interstate pipeline system via the Chicago Hub. Four interstate, and two intrastate, pipelines receive natural gas at the Aux Sable plant tailgate.

- **Since 1995, average daily natural gas plant processing capacity in the United States increased by 49 percent as new and larger capacity plants were installed and a number of existing ones were expanded.** Over the past 10 years, average plant capacity increased from 76 million cubic feet per day (MMcf/d) to 114 MMcf/d and decreased in only 4 of the 22 States with natural gas processing plant capacity (Table 1). In Texas, although the number of plants and overall processing capacity decreased, the average capacity per plant increased from 66 MMcf/d to 95 MMcf/d as newer plants were added and old, less efficient plants were idled. In Alabama, Mississippi, and the eastern portion of South Louisiana, new larger plants and plant expansions built to serve new offshore production increased the average plant capacity significantly in those areas.

- **Expanding natural gas production in Wyoming in recent years led to the installation of seven new gas processing plants and the expansion of several more.** Since 1995, Wyoming's natural gas plant processing capacity increased by almost 46 percent, adding more than 2.2 Bcf/d (Table 1). Much of the activity has been focused in the southwestern area of Wyoming's Green River Basin where one of the nation's largest gas plants, the Williams Company's 1.1 Bcf/d Opal facility, is located. Increased natural gas development behind the plant and a significant expansion of pipeline capacity at

Figure 2. Concentrations of Natural Gas Processing Plants, 2004



Note: Eight Alaska plants not displayed, but count is reflected in the legend.
Source: Energy Information Administration, Gas Transportation Information System, Natural Gas Processing Plant Database.

the plant tailgate (Kern River Transmission and Northwest Pipeline systems) necessitated two significant plant expansions at Opal since 2000, the last being a 350-MMcf/d increase in early 2004.

- **Successful exploration and development in the Piceance Basin in western Colorado and increased natural gas production in the San Juan Basin in southern Colorado have contributed to the installation of 13 new or replacement plants in the State and the expansion of several existing facilities.** In part, these increases have supported the installation of new pipeline systems in the region such as the TransColorado Gas Transmission system built in 1999, which can transport up to 650 MMcf/d of Piceance and San Juan basin production to interstate pipeline connections with western markets.

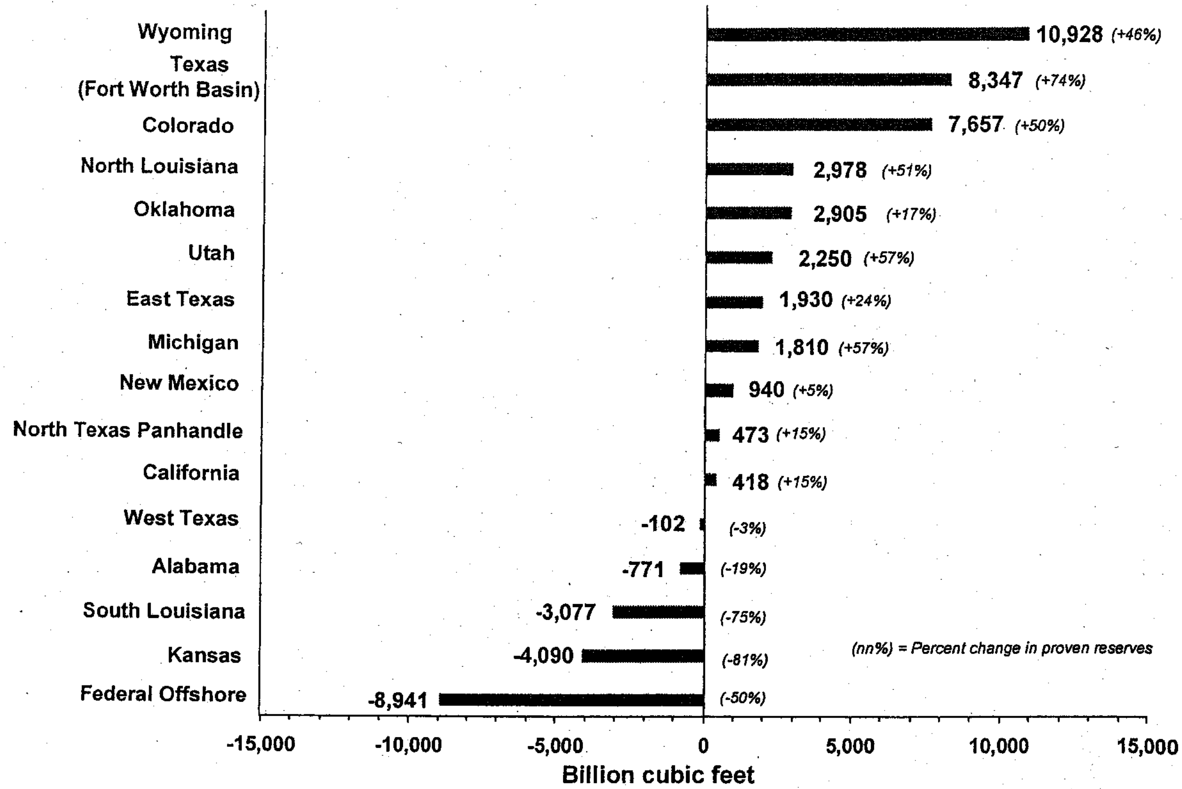
Over the next several years, additional new natural gas processing plants and capacity can be expected to be installed in Wyoming and Colorado as exploration and development efforts in those States continue, especially if the prices of natural gas and natural gas liquids remain high. Increased exploration and development has increased the level of proved natural gas reserves in these two States by more than 45 percent, or 18.6 trillion cubic feet, since 1995 (Figure 3).

Moreover, it can be expected that new plant capacity will be needed in other areas currently undergoing increased exploration and development, such as the Fort Worth Basin in northeast Texas (gas shale), the Texas panhandle, and the east Texas area. Since 1995, growth in the level of proved natural gas reserves in these areas has been significant.

Shift in Installation Patterns

While a number of market factors can influence the location and level of gas processing capacity in the United States, shifts in exploration and development activity and subsequent changes in natural gas production levels have had the greatest impact during the past 10 years. The level of overall natural gas plant processing capacity in an area follows the development of new oil and gas fields (rise in supply) and the decline of older fields (fall in supply).

Figure 3. Major Changes in Proved Natural Gas Reserves, 1995 to 2004
(Wet after lease separation)



Source: Energy Information Administration, *U.S. Crude Oil and Natural Gas, and Natural Gas Liquids Reserves, 1995 and 2004 Annual Reports*: Table 9.

As natural gas production (Table 2) and annual added proved reserves (Figure 3) decreased significantly in southern Louisiana and the Gulf of Mexico (GOM) between 1995 and 2004,[15] several natural gas processing plants in the region were idled, especially in the western portion of the region where older production fields are predominate. However, in the deepwater and eastern portion of the Gulf several substantial new natural gas deposits were developed and began producing during the period. Subsequently, new natural gas production facilities and new gathering pipelines were built to deliver this natural gas onshore. To accommodate these new natural gas flows, eight natural gas plants located in southern Louisiana were expanded. These expansions helped increase Louisiana's overall natural gas plant capability by 6 percent between 1995 and 2004, despite declining overall natural gas production both onshore and off.

Increased deepwater natural gas development also affected the number and capacity of natural gas processing facilities in Alabama and Mississippi. In Alabama, two of the seven new processing plants installed after 1995 were principally dedicated to processing offshore production delivered via the Dauphin Island Gathering System and Transco's Mobile Bay lateral. Both were large 600-MMcf/d facilities located along Mobile Bay.[16] In Mississippi, a new 500-MMcf/d plant was developed in the mid-1990s at Pascagoula, primarily to serve onshore production. The plant's capacity was doubled in 2000 in order to accept natural gas from the offshore via the new Destin Pipeline. Growth in natural gas processing demand owing to new offshore production brought Mississippi and Alabama, from a ranking (by overall capacity) of 18th and 11th, respectively, in 1995, to 9th and 10th in 2004.

The Rocky Mountain States have seen expanding development of coalbed methane resources as well as steadily increasing exploration/development efforts and

[15]In 1995, proved gas reserve additions from new fields and new reservoir discoveries in old fields in southern Louisiana and the Gulf of Mexico amounted to 3,174 Bcf (wet basis) with gas production at 5,827 Bcf, while the corresponding figures in 2004 were 991 Bcf and 4,866 Bcf, respectively. Energy Information Administration, *U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves*, 1995 and 2004 Annual Reports, Table 9.

[16]In 2004, a co-owner of one of the facilities removed one processing train (300 MMcf/d) from the plant and moved it to Louisiana.

Table 2. Major Lower 48 Natural Gas Producing States and Federal Offshore

(Volumes in Trillion Cubic Feet)

	Wet Gas Production		Percentage Change	Processed Volume (Gas to Liquids)		Percent Processed	
State	1995	2004	1995-2004	1995	2004	1995	2004
Texas	5.11	5.66	10.8	0.39	0.35	7.6	6.2
Federal Offshore	4.67	4.01	-14.0	0.04	0.09	0.9	2.3
Oklahoma	1.66	1.66	-0.2	0.10	0.10	6.0	5.8
New Mexico	1.48	1.62	9.7	0.08	0.09	5.4	5.7
Wyoming	0.84	1.59	89.4	0.03	0.07	3.6	4.5
Louisiana	1.50	1.36	-9.5	0.10	0.04	6.7	2.8
Colorado	0.54	1.09	101.1	0.03	0.04	5.6	3.3
Kansas	0.71	0.40	-43.1	0.08	0.02	11.3	5.9
Total	16.51	17.39	5.3	0.85	0.80	5.1	4.6

Source: Energy Information Administration, *U.S. Crude Oil and Natural Gas, and Natural Gas Liquids Reserves: 1995 and 2004 Annual Reports.*

growing production from tight-sands and conventional natural gas sources. As a result, significant increases in natural gas plant processing capacity in Wyoming, Colorado, and Utah have occurred. While Montana has much less overall natural gas processing capacity than the other Rocky Mountain States, it too experienced an increase in processing capacity (Table 1) as natural gas production in the State rose by 16 percent and proved reserves grew by 27 percent during the past decade.

As mentioned earlier, the number of plants and the level of natural gas processing capacity in Texas decreased by 40 and 13 percent, respectively, between 1995 and 2004. While natural gas production within Texas increased overall during that time period, several areas such as the Permian Basin in the western part of the State experienced decreases. A number of natural gas plants in that area were idled while new processing plants were built in developing areas such as the Fort Worth Basin area in northeast Texas.

In most of the country, the increases and decreases in installed natural gas processing capacity have closely tracked the changes in proved natural gas reserves since 1995. Moreover, where significant new proved reserves have been added, the expectation is that eventually new natural gas production will follow, and new natural gas processing plants will need to be installed accordingly (Figure 3).

Impact of Restructuring

As the FERC-mandated restructuring of the natural gas industry[17] took effect during the 1990s, changes also occurred in the economics of natural gas processing plant ownership. Before restructuring, many natural gas processing plants were owned and operated by natural gas and oil producers as part of their overall energy production and marketing business. With restructuring, many of these producers sold their natural gas processing facilities in order to focus on exploration and development activities.

Before restructuring, more than 310 individual companies owned and/or operated natural gas processing plants. By 1995 there were 270 companies, and by 2004 the number had dropped to 209. Yet, the amount of new processing capacity rose by 8.9 percent during the same 9-year period (Table 1). As competition increased and the economics of production and processing changed under restructuring, consolidation of plant ownership significantly increased. In 2004, for instance, the top 10 natural gas plant owner/operators had access to or owned about 74 percent (44.5 Bcf/d) of the total natural gas plant capacity in the United States. This compares with about half that much in 1995, although the percentage of plants owned/operated remained at about 36 percent.

Between 1995 and 2004, the type of companies owning/operating processing plants shifted from primarily oil/gas producers to what are now referred to as "midstream" companies or operating divisions. These entities focus their efforts on the natural gas gathering, natural gas processing, and natural gas storage operations segments of the industry. In 1995 production companies such as Shell Western E&P, Texaco Production, Exxon Co USA, and Warren Petroleum controlled the largest share of natural gas plant processing capacity. In 2004, however, midstream operating companies such as Duke Energy Field Services (54 plants, 7.5 Bcf/d capacity), Enterprise Products Operating LP (26, 6.3 Bcf/d), Targa Resources[18] (21, 3.4 Bcf/d), and BP PLC (13, 5.6 Bcf/d), predominate.[19]

Natural Gas Processing Cost Recovery

The primary role of a natural gas processing plant in today's marketplace is to produce pipeline-quality natural gas. The production of natural gas liquids and other products from the natural gas stream is secondary. The quantity and quality of the byproducts actually produced during a particular time period is, in many instances, a function of their current market prices. If the market value of a byproduct falls below the current production cost, a natural gas plant owner/operator may suspend its production temporarily. In some instances, a plant operator may increase the Btu content of its plant residue (plant tailgate) gas stream, as long as it remains within pipeline tolerances, in order to absorb some of the byproducts. In other cases the raw liquid stream (minus methane) is stored on-site temporarily or sold off.

[17] FERC Order 636, issued in 1993, primarily dealt with revising how interstate pipeline companies did business. Order 636 required interstate pipeline companies to change from buying and selling the natural gas they transported to selling the transportation service only.

[18] In late 2005, Targa Resources, Inc., acquired the gas processing plant interests of Dynegy Midstream Services LP in Louisiana, Texas, and New Mexico. In combination with its existing gas plant assets, the acquisition moved Targa Resources significantly higher in the rankings of midstream companies.

[19] In those cases where a gas plant is not fully owned by the party, a percentage of the total capacity of the plant equal to the ownership percentage was included in the Bcf/d capacity item.

As noted earlier, before restructuring of the natural gas industry in the 1990s, most natural gas processing was performed by an affiliate of the production company. The processor was reimbursed through what is commonly referred to as a keepwhole contract.[20] Under such a contract the NGLs recovered at the facility are retained by the processor as payment, while the other party's delivery is "kept whole" by returning an amount of residue (plant tailgate) natural gas (equal on a Btu basis to the natural gas received at the plant inlet) at the tailgate of the plant.

In today's more competitive restructured marketplace, where supply/demand fluctuations are more commonplace, natural gas prices are more variable, and price levels are relatively high compared with other forms of energy, including NGLs, "keepwhole" arrangements tend to create income uncertainty for processors. Such arrangements are profitable when the value of the NGLs is greater as a separated liquid than as a portion of the residue natural gas stream; they are less profitable when the value of the NGLs is lower as a liquid than as a portion of the residue natural gas stream.

As a result, participants in the natural gas processing industry have been replacing keepwhole contracts with alternative arrangements as the contracts come up for renewal. Several unique types of natural gas processing arrangements are being offered in their place. Among them are: percent-of-liquids contracts, percent-of-index contracts, margin-band contracts, fee-based contracts, and hybrid contracts. In broad terms, they function as follows:

- *Percent-of-liquids or percent-of-proceeds.* With this type of contract the processor takes ownership of a percentage of the NGL mix extracted from a producer's natural gas stream. The producer either retains title to, or receives the value associated with, the remaining percentage of the NGL mix. The producer reimburses the processor for the costs involved in the liquids extraction operation.
- *Percent-of-index contracts.* Under this type of contract the processor generally purchases its natural gas at either a percentage discount to a specified index price, a specified index price less a fixed amount, or a percentage discount to a specified index price less an additional fixed amount. The processor then resells the natural gas at the index price or at a different percentage discount to the index price.
- *Margin-band contracts.* Under this type of arrangement the processor takes ownership of NGLs extracted from the natural gas stream delivered by the producer, while the producer is paid a return based on the energy value of the NGL mix that was extracted from the natural gas stream less the fuel consumed in the extraction process. Both parties accept specified floor and ceiling return levels which are intended to provide an acceptable return to each party when natural gas processing economics tend to become negative or the economic gains become excessive.
- *Fee-based contracts.* In these contracts a set fee is negotiated based on the anticipated volume of natural gas to be processed. The producer either retains title to, or receives the value associated with, any NGLs extracted and is responsible for all energy costs of processing.
- *Hybrid contracts.* Such arrangements usually provide processing services to a producer under a monthly percent-of-liquids arrangement initially, with the producer having the option of switching to either a fee-based arrangement or in certain cases to a keepwhole basis. The intent is to give both producer and processor the incentive to maintain operations during periods of natural gas price swings, especially during those periods when the price of natural gas is high relative to the economic value of NGLs.

Contracts for natural gas processing have terms ranging from month-to-month to the life of the producing lease. Intermediate terms of 1 to 10 years are also common.

Outlook and Potential

Since 1995, natural gas plant processing capacity has increased by almost 9 percent (Table 1), with most of this growth following new production field development. Based upon trends that have developed over the past several years, especially in the finding of newly proved reserves (Figure 3), or lack thereof, two areas of the country in particular could experience sizable shifts in natural gas processing plant resources, with increases expected in the Rocky Mountain area and decreases expected along the Gulf Coast.

Continuing a trend begun in the late 1990s, ongoing expansion of natural gas exploration and development in Colorado, Utah, and Wyoming could add to natural gas plant processing requirements over the next several years.[21] Each of these States experienced a 25 percent or greater increase in installed natural gas processing plant capacity over the past decade. It is generally anticipated that the Unita Basin of eastern Utah and the Piceance Basin of western Colorado will become more actively developed over the next decade, with several new large-scale capacity natural gas pipelines scheduled to be installed to transport the produced natural gas

[20] Much of the background material used in this section is based on information and discussions of gas processing contracts found in the 2004 SEC 10K filings of Enterprise Products Partners LP and MarkWest Energy Partners LP.

[21] On November 30, 2005, EnCana Ltd announced that it has begun construction of a new 650 MMcf/d natural gas processing plant in northwestern Colorado to accommodate increasing natural gas production in the Piceance Basin. The plant is scheduled to be in service in early 2007. Platts Inc., *Gas Daily*, December 1, 2005, p. 4.

to western and midwestern markets.[22] These new pipelines will also need new processing plants to be installed to treat this natural gas prior to receipt.

New natural gas processing capacity will perhaps be needed in Texas as well. Despite a net decrease in natural gas plant capacity in the State of about 13 percent between 1995 and 2004 (Table 1), several new plants were added and others are planned as a result of increased development in the Barnett Shale Formation of the Fort Worth Basin in northeast Texas. The gas shales located in this area, which encompasses several counties north and west of Dallas, Texas, were once considered uneconomical to develop, but the advent of new technologies has greatly improved its potential and, thus, its attraction to natural gas producers.

In southern Louisiana and the Gulf of Mexico, on the other hand, decreasing natural gas production and a significant drop in the volume of new proved natural gas reserves found in the region during the past decade likely will slow growth of natural gas processing capacity along the Gulf Coast over the next several years. However, since the Gulf of Mexico and southern Louisiana will remain the largest natural gas producing area in the country for years to come, most existing natural gas processing plants in the region should remain active, although perhaps processing at lower daily flow rates.

The potential remains, nevertheless, for the discovery of some major natural gas finds in the deepwater regions of the Gulf, which could lead to expansion of some existing plants or even installation of an occasional new one. However, in the short term, this seems unlikely. No new offshore-to-onshore pipelines are scheduled for development through 2008, except for those related to LNG imports through the Gulf States.[23] The lack of proposals for pipeline development would tend to indicate that existing plant capacity serving the Gulf of Mexico is adequate for the foreseeable future.

Although gross natural gas production in the United States has remained relatively level since 2000,[24] rising natural gas wellhead prices can be expected to lead to increases in natural gas exploration and development efforts. Some increases in production could occur in the older production fields, but much of the additional natural gas production will probably come from newly developed reserves found in the areas mentioned above. Consequently, as new sources of production are developed, new processing facilities, or greater use of now-underutilized plant capacity, will follow suit, while some older facilities, particularly those taking gas from depleting areas, will be closed or relocated.

[22] Energy Information Administration, Gas Transportation Information System, Natural Gas Pipeline Projects Database, as of December 2005.

[23] Imported LNG supplies often have higher Btu content than domestic natural gas supplies and may need to be processed to meet U.S pipeline quality specifications. The introduction of additional LNG volumes into the Gulf area may increase processing plant utilization beyond what is required for domestic natural gas production. However, this need is uncertain and depends on the construction of new facilities and the quality of the future LNG imports.

[24] See Energy Information Administration, *Natural Gas Annual 2004*, (Washington, D.C. December 2005), Table 1. http://www.eia.doe.gov/oil gas/natural gas/data publications/natural gas annual/nga.html